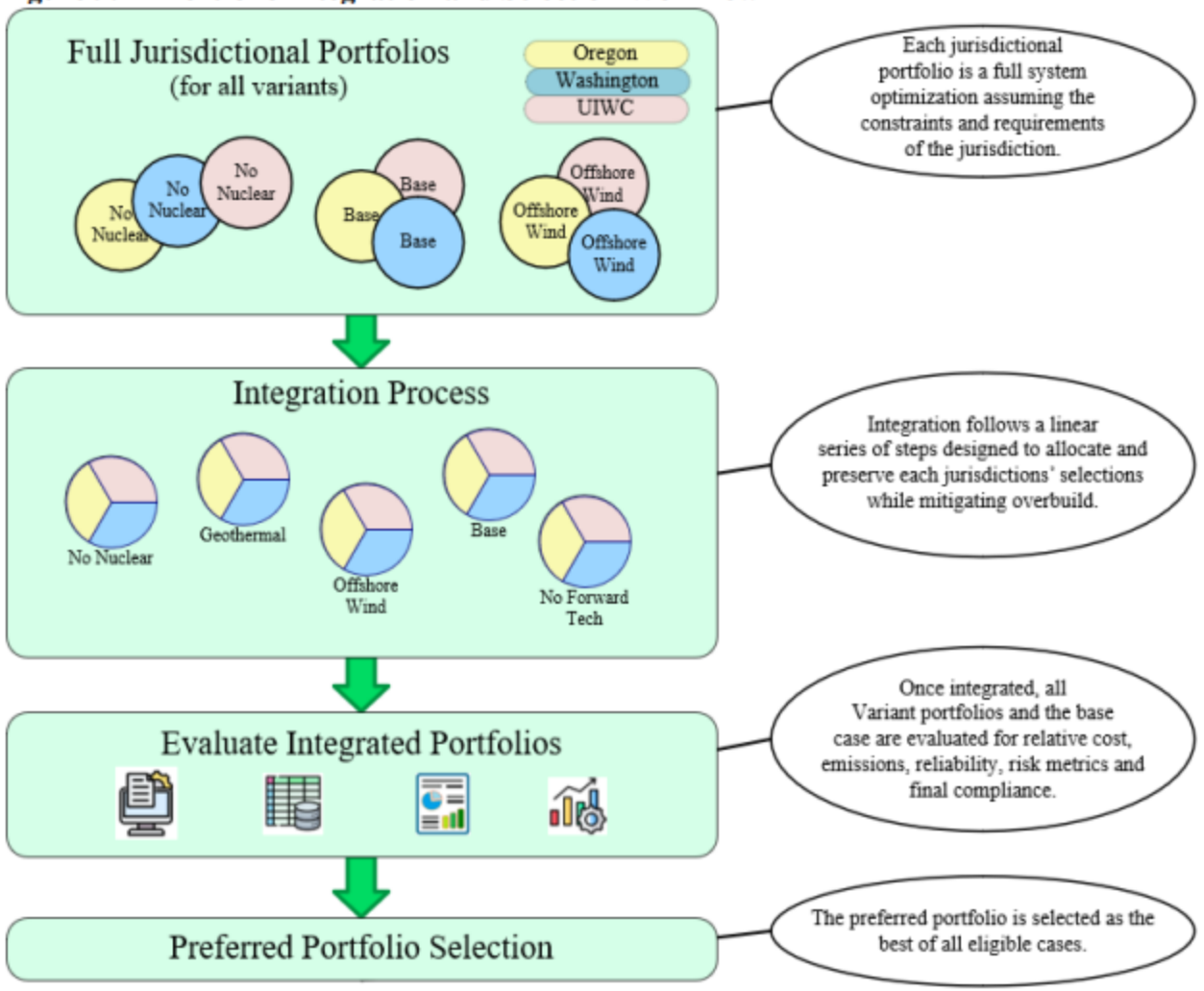
2025 Utah Schedule 37 Avoided Cost Update
Technical Conference 6/18/2025

PACIFICORP®
POWERING YOUR GREATNESS

Utah 2025 IRP Integration Methodology

Volume I, Chapter 9, page 218

Figure 9.1 – Portfolio Integration and Selection Workflow



Utah 2025 IRP Preferred Portfolio

Table 12.7 – Utah, Idaho, Wyoming, California (UIWC) Full Jurisdictional Portfolio

Resource	Installed Capacity, MW							
	2025	2026	2027	2028	2029	2030	2031	2032
Expansion Options								
Renewable - Wind	-	-	-	486	211	-	-	1,045
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	-	-	-	-	1,675
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-

Table 2
2025 IRP Utah - Detailed Integrated Preferred Portfolio

Resource	Installed Capacity (MW)							
	2025	2026	2027	2028	2029	2030	2031	2032
Expansion Options								
Utility Scale Wind - DJ/Wyodak Gen	-	-	-	486 (d/Q)	211	-	-	-
Utility Scale Solar - Central OR	-	-	136	16	-	-	-	-
Utility Scale Solar - Southern OR	-	-	-	-	-	-	0	-
Utility Scale Solar - Summer Lake	-	-	-	1	-	-	-	353
Utility Scale Solar - Walla Walla - WA	-	-	-	1	-	-	794	-
Utility Scale Solar - Willamette Valley	-	-	109	164	-	287	34	451 (d/Q)
Utility Scale Solar - Yakima	-	-	0	-	-	561	68	1
Utility Scale Wind - Willamette Valley	-	-	-	-	594	-	-	451

Table 2- Detailed Portfolio tab in Workpaper "25-035-T03 RMP Appendix 1 - AC Study Summary 04-30-25.xlsx"
PacifiCorp's 2025 IRP Utah Workpapers, Chapter 12 ("LT_25I.LP.iLT.21.Integrated.EP.2409MN.Base IntTrans_106955 v78.1.xlb"

From Table 12.4 Utah 2025 IRP
UIWC Shares by Resource Type and Year, Installed MW

Resource	Installed Capacity (MW)							
	2025	2026	2027	2028	2029	2030	2031	2032
Expansion Options								
Utility Scale Wind - DJ/Wyodak Gen	-	-	-	403 (d/Q)	211 (d)	-	-	-
Utility Scale Solar - Central OR	-	-	-	-	-	-	-	-
Utility Scale Solar - Southern OR	-	-	-	-	-	-	-	-
Utility Scale Solar - Summer Lake	-	-	-	-	-	-	-	-
Utility Scale Solar - Walla Walla - WA	-	-	-	-	-	-	-	-
Utility Scale Solar - Willamette Valley	-	-	-	-	-	-	-	225 (d/Q)
Utility Scale Solar - Yakima	-	-	-	-	-	-	-	1
Utility Scale Wind - Willamette Valley	-	-	-	-	-	-	-	451 (d)

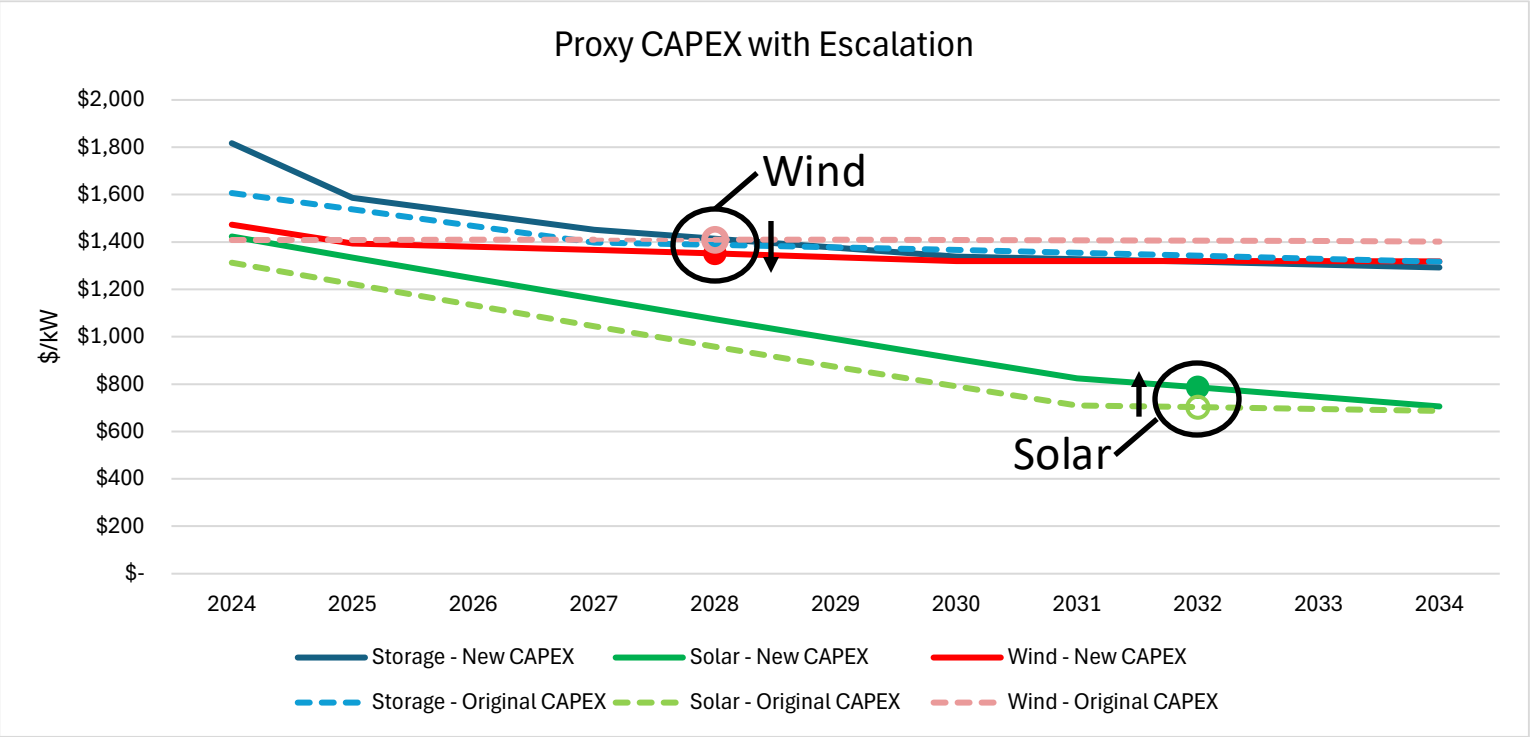
Footnotes:
(Q) Partially Deferred Proxy Resource by UT Sch 37 QF
(d) Deferrable by UT QFs

Comparison of Capacity Contribution Assumptions

- Under the approved Partial Displacement Differential Revenue Requirement (PDDRR) methodology, a QF displaces a capacity contribution equivalent amount of a proxy resource, with wind and solar displacing proxy resources of the same type. The displaced megawatts of the proxy resource are removed from the portfolio and the avoided fixed costs are used in calculation of the capacity payment.
  - Tracking solar capacity contributions fell slightly, but the ratio of the QF and proxy are similar.
  - Fixed-tilt solar capacity contributions fell significantly, based on the timing/alignment with loss of load events in the 2025 IRP. Capacity deferral drops significantly, but the impact on avoided costs is relatively small as solar resource costs are relatively low.
  - Wind capacity contribution in Utah dropped slightly, but contribution of Wyoming wind dropped more, so proxy resource displacement is higher. Because the proxy wind resource costs are relatively low and its capacity factor is relatively high, higher displacement doesn't necessarily result in higher avoided costs.

2024 Sch 37 Filing			2025 Sch 37 Filing		
Capacity Contribution %		**Displacement MW**	**2025 Filing**		**Displacement MW**
Solar Tracking QF - Utah North	14.0%	10 MW *(14%/14.2%) w 3 yrs Degrad = 9.7 MW	Solar Tracking QF - Utah North	10.8%	10 MW *(10.8%/10.7%) w 7 yrs degrad = 9.7 MW
Solar Proxy - Central Oregon	14.2%		Solar Proxy - Willamette Valley	10.7%	
Solar Fixed-Tilt QF - Utah North	13.3%	10 MW *(13.3%/14.2%) w 3 yrs Degrad = 9.3 MW	Solar Fixed-Tilt QF - Utah North	3.0%	10 MW *(3.0%/10.7%) w 7 yrs degrad = 2.7 MW
Solar Proxy - Central Oregon	14.2%		Solar Proxy - Willamette Valley	10.7%	
Wind QF-Utah North	18.9%	10 MW *(18.9%/30.6%) = 6.2 MW	Wind QF-Utah North	18.2%	10 MW *(18.2%/25.8%) = 7.1 MW
Wind Proxy - Wyoming	30.6%		Wind Proxy - Wyoming (DJ)	25.8%	
Based on 2021 IRP Appendix K			Based on 2025 IRP Appendix K		

Correction to 2025 IRP Proxy Resource Cost Escalation



Following the filing of the 2025 IRP, PacifiCorp identified an error in the escalation rates applied to solar, wind, and storage resources:
Escalation rates for proxy resources started in 2025 but should have been applied from the earliest commercial operation year.

For proxy resources used in proposed Schedule 37 rates:

- Wind resource costs drop slightly for 2028 COD. Avoided costs would go down slightly.
- Solar resource costs increase for 2032 COD. Avoided costs would go up.

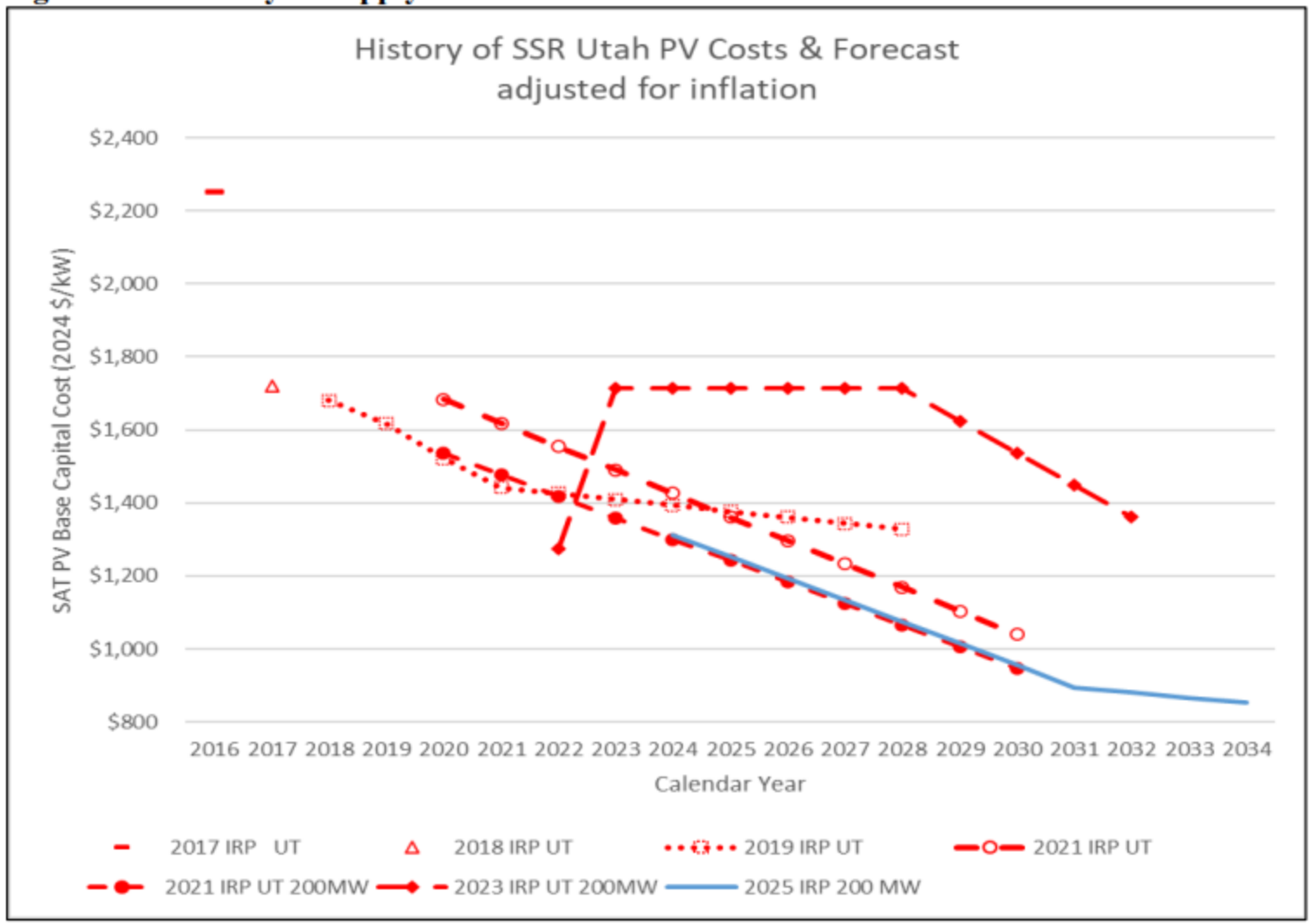
Lower wind costs could increase the amount of wind resource selections, while higher solar costs could reduce the amount of solar resource selections.

Solar Resource Cost Escalation History

In 2023 IRP, solar resource costs were set based on recent offers received in summer 2022 for CY2023-2028, then trended back to values reported by NREL's 2022 Annual Technology Baseline by 2032.

In 2025 IRP, solar resource costs were intended to reflect values and escalation reported by NREL's 2024 Annual Technology Baseline throughout the horizon. The correction described in the previous slide is not reflected in this slide from the 2025 IRP document.

Figure 7.1 – History of Supply-side Resource PV Cost & Forecast

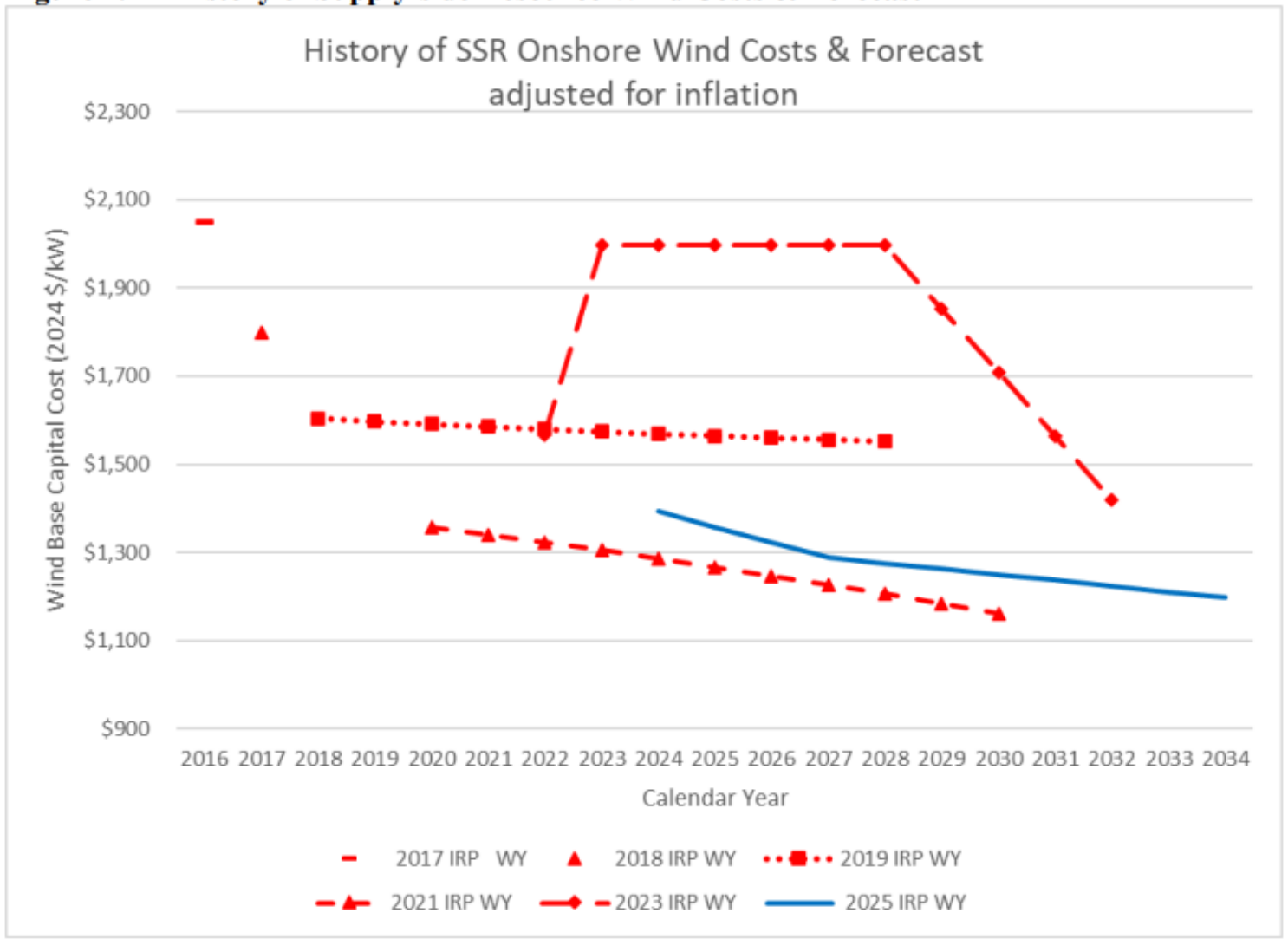


Wind Resource Cost Escalation History

In 2023 IRP, wind resource costs were set based on recent offers received in summer 2022 for CY2023-2028, then trended back to values reported by NREL's 2022 Annual Technology Baseline by 2032.

In 2025 IRP, wind resource costs were intended to reflect values and escalation reported by NREL's 2024 Annual Technology Baseline throughout the horizon. The correction described in the previous slide is not reflected in this slide from the 2025 IRP document.

Figure 7.2 – History of Supply-side Resource Wind Costs & Forecast



Proxy Resource Costs assumptions

Approved Rate: Docket 24-035-T04
- **2023 IRP cost assumptions**
- **2023 IRP Update preferred portfolio**

	Deferred Proxy Resource	Proxy C.F.	Size of Displacement (MW)	Year	Total Fixed Cost with Tax Credit ($/kW-yr) in COD year
Baseload	UTN, GSC, 395 MW, UWIC	33%	10.7 MW	2029	$109.46
Wind	UTN-UWY, Wind, 39 MW-UIWC	43.6 %	6.2 MW	2027	$196.55
Solar, tracking	COR, Solar, 38 MW-UIWC	29.3 %	9.7 MW	2027	$172.27
Solar, fixed	COR, Solar, 38 MW-UWIC	29.3 %	9.3 MW	2027	$172.27

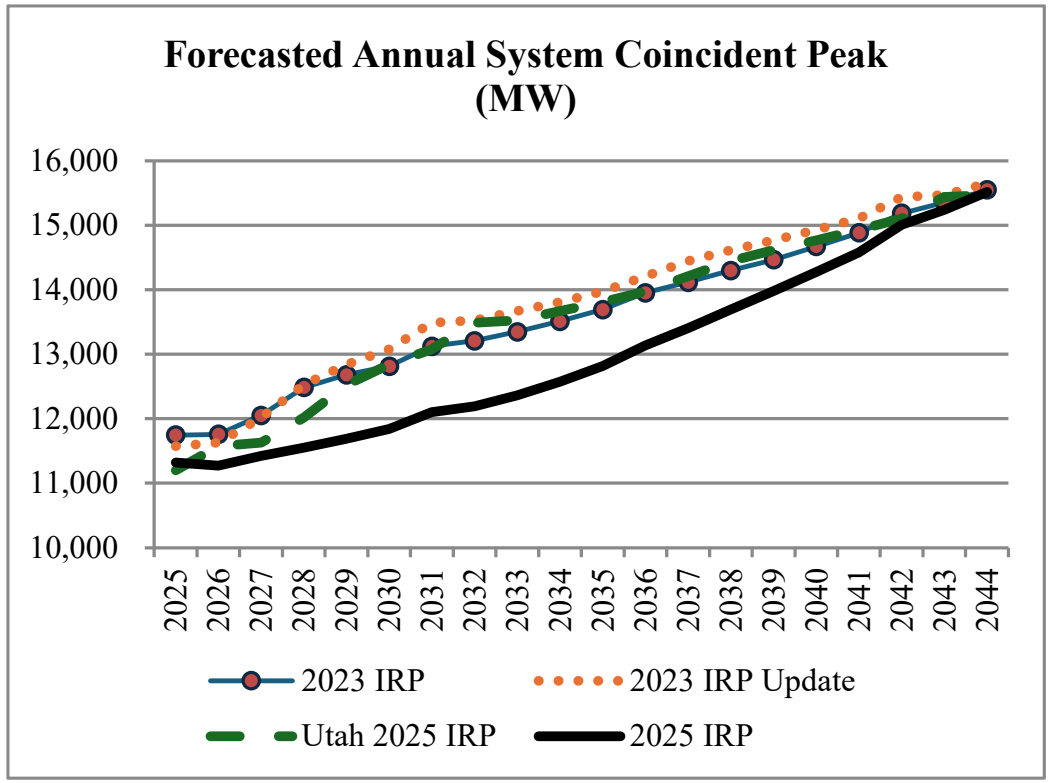
Proposed Rates: Docket 25-035-T03
- **2025 IRP cost assumptions**
- **2025 IRP Update preferred portfolio**

Deferred Proxy Resource	Proxy Capacity Factor	Size of Displacement (MW)	Year	Total Fixed Cost with Tax Credit ($/kW-yr) in COD year
No Thermal resource available to defer	N/A	N/A	N/A	N/A
DJ, Wind, 403 MW - UWIC	41.2%	7.1 MW	2028	$126.4
Willamette Valley, Solar, 226 MW-UWIC	24.5%	9.7 MW	2032	$114.05
Willamette Valley, Solar, 225-UWIC MW	24.5%	2.7 MW	2032	$114.05

Escalation Rate Correction: Docket 25-035-T03
- **2025 IRP cost assumptions with corrected escalation**
- **2025 IRP Update preferred portfolio**

Deferred Proxy Resource	Proxy Capacity Factor	Size of Displacement (MW)	Year	Total Fixed Cost with Tax Credit ($/kW-yr) in COD yr
No Thermal resource available to defer	N/A	N/A	N/A	N/A
Dave Johnston, Wind, 403.4 MW	41.2%	7.1 MW	2028	$122.61 = $126.4 - $3.79 (Esc. rate correction)
Willamette Valley, Solar, 226 MW	24.5%	9.7 MW	2032	$122.41 = $114.05 + $8.35 (Esc. rate correction)
Willamette Valley, Solar, 225 MW	24.5%	2.7 MW	2032	$122.41 = $114.05 + $8.35 (Esc. rate correction)

(Q3) Compare Recent Coincident Peak Load Forecasts



The 2023 IRP, 2023 IRP Update, and Utah 2025 IRP have similar peak loads.
The Utah 2025 IRP excluded some large new customer loads.
The 2025 IRP excluded all projected large new customer loads.

In general, higher loads result in higher avoided costs.

- Higher load results in more resource additions – more opportunities for resource deferral, and potentially the addition of more expensive resource options.
- Higher load results in higher output from marginal resources, or shifting to a more expensive resource which results in higher marginal costs.

PacifiCorp expects to negotiate special contracts with large new load customers. Resources and transmission to serve those customers would be identified as part of contract negotiations. The resources identified would need to be sufficient to ensure WRAP compliance is maintained with the new load addition.

(Q4) Schedule 37 Step Updates

		Levelized Avoided Cost (2026-2040)					
Type	**Filing**	**Base Load**	**Wind**	**Solar Tracking**	**Portfolio**	**QF Queue (Solar MW)**	**Key driver**
Sch 37	**May 2024**	$53.73	$27.49	$39.00	23IRP Update	n/a	
Sch 38	Jun 2024 (2024.Q1)	$53.76	$28.97	$29.71	23IRP Update	365	Inclusion of QF queue solar
Sch 38	Sep 2024 (2024.Q2)	$54.12	$28.81	$36.67	23IRP Update	164	Reduction in QF queue/lower market prices
Sch 38	Dec 2024 (2024.Q3)	$52.51	$28.37	$36.31	23IRP Update	164	Lower market prices
Sch 38	Mar 2025 (2024.Q4)	$51.76	$28.03	$35.56	23IRP Update	8	Lower market prices
Sch 37	**April 2025**	$30.93	$18.13	$23.80	Utah 2025 IRP	n/a	IRP resource cost update
Sch 38	May 2025 (2025.Q1)	$30.77	$17.27	$23.41	Utah 2025 IRP	0	80 MW Sch 38 proxy vs 10 MW Sch 37 proxy
Sch 37	**April 2025 (Corrected**	*$30.93*	$17.22	$25.51			Corrected resource cost escalation

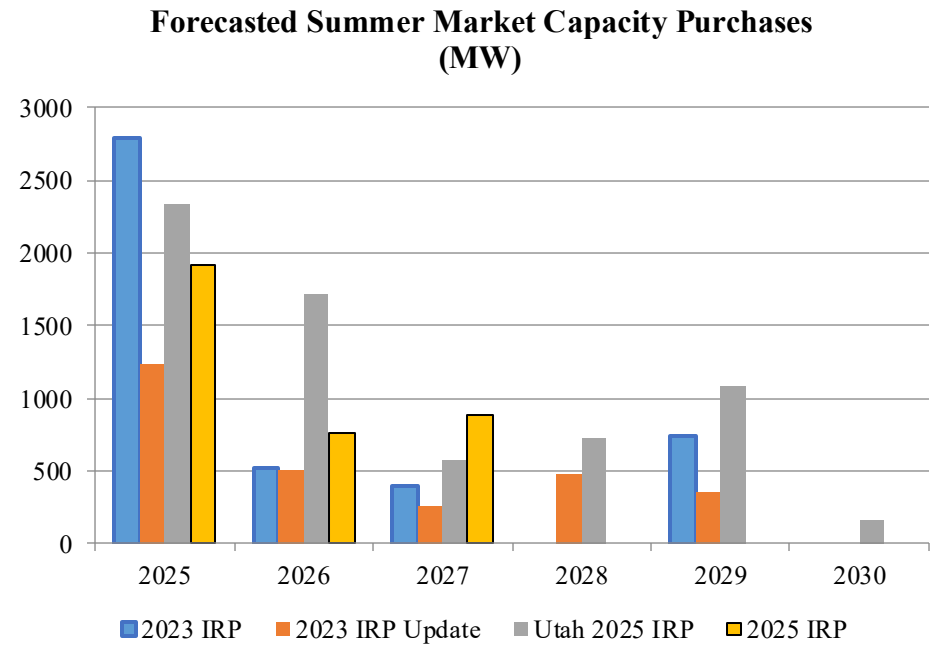
Schedule 37 and Schedule 38 reflect the same methodology, except:

- Schedule 37 excludes potential QFs, only signed contracts.
- Schedule 38 also includes potential QFs: earlier QF requests that are timely working through the negotiation process.
- Each additional resource in the queue tends to result in lower avoided costs.

PacifiCorp produces quarterly updates of Schedule 38 avoided cost inputs, see Dockets No. 25-035-30, 24-035-35, etc.

(Q5) Market Purchases Comparison

Market Purchases for Capacity, a.k.a. Front Office Transactions (FOTs), as shown in recent load and resource balance results.



- IRP modeling does not allow resource additions in the first few years of the horizon.
- Short-term market products are assumed to be used to meet any open position prior to the modeled availability of new resources.
- **2023 IRP Update:** long-term resources available in 2027.
- Following the 2023 IRP Update filing, PacifiCorp executed contracts for battery resources that will achieve CODs prior to summer 2026.
- **Utah 2025 IRP**: some resources in 2027, most resources available starting 2028.
- **2025 IRP (Chapter 9)**: long-term resources available in 2028.

- Short-term market purchases are expected to be lower cost than long-term resources, but may not always be available.
- New for the 2025 IRP, to ensure compliance with Western Program and Enhanced Day-Ahead Market requirements, market purchases were not allowed starting in 2028 on the top five load days in each month, during 4 p.m. to 12 a.m. in summer and winter, and in 4 a.m. to 8 a.m. in the winter only.
- Market purchases are allowed for economics in other periods, when resource availability is higher.

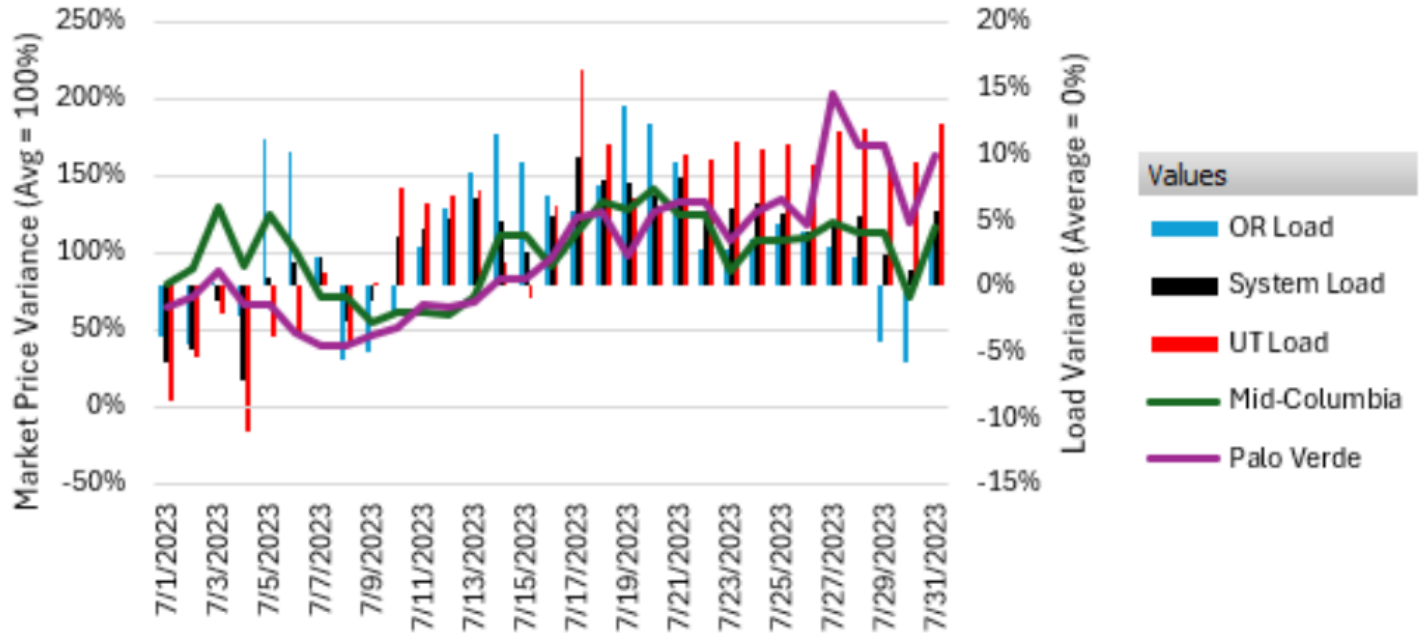
(Q5) Market Purchases and Avoided Costs

Avoided Costs are primarily impacted by market purchases in hourly energy balancing.

- Dispatchable resources are backed down when their variable costs are higher than the market price
  - The addition of a QF will avoid the need for market purchases, frequently in low market price hours
- Dispatchable resources are dispatched up when their variable costs are higher than the market price
  - The addition of a QF will be more likely to avoid fuel costs in high market price hours
- When insufficient dispatchable resources are available, QF can avoid expensive market purchases

The 2025 IRP incorporated daily market price volatility, tied to the historical conditions from the same day as the load, wind, solar, and thermal outages. Market prices are volatile, but tend to be higher when load is high, and lower when resource availability is high.

Figure H.5 -- Historical Market Prices vs Load, July 2023

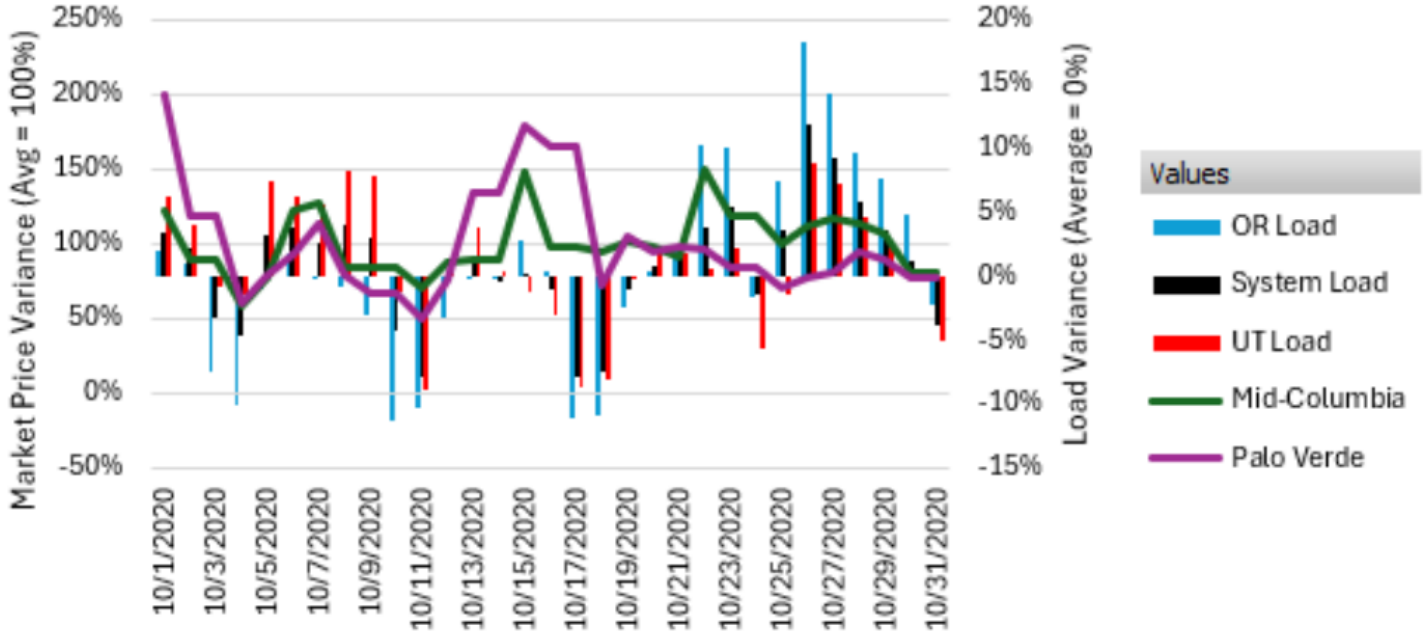


(Q5) Market Purchases and Avoided Costs

With increased daily market price volatility, the monthly average price stays the same, but:

- Market prices tend to be lower when dispatchable resources are backed down
  - The addition of a wind or solar QF will tend to avoid the need for lower priced market purchases
- Market prices tend to be higher when dispatchable resources are dispatched up
  - Avoided fuel costs reflect daily natural gas costs, but impact is smaller than variation in power prices.
- When insufficient dispatchable resources are available, QF can avoid expensive market purchases

Figure H.6 – Historical Market Prices vs Load, October 2020



(Q6) Natrium Resource

Terrapower's Natrium™ project (Kemmerer Power Station Unit 1) is part of the Utah 2025 IRP preferred portfolio in 2030:

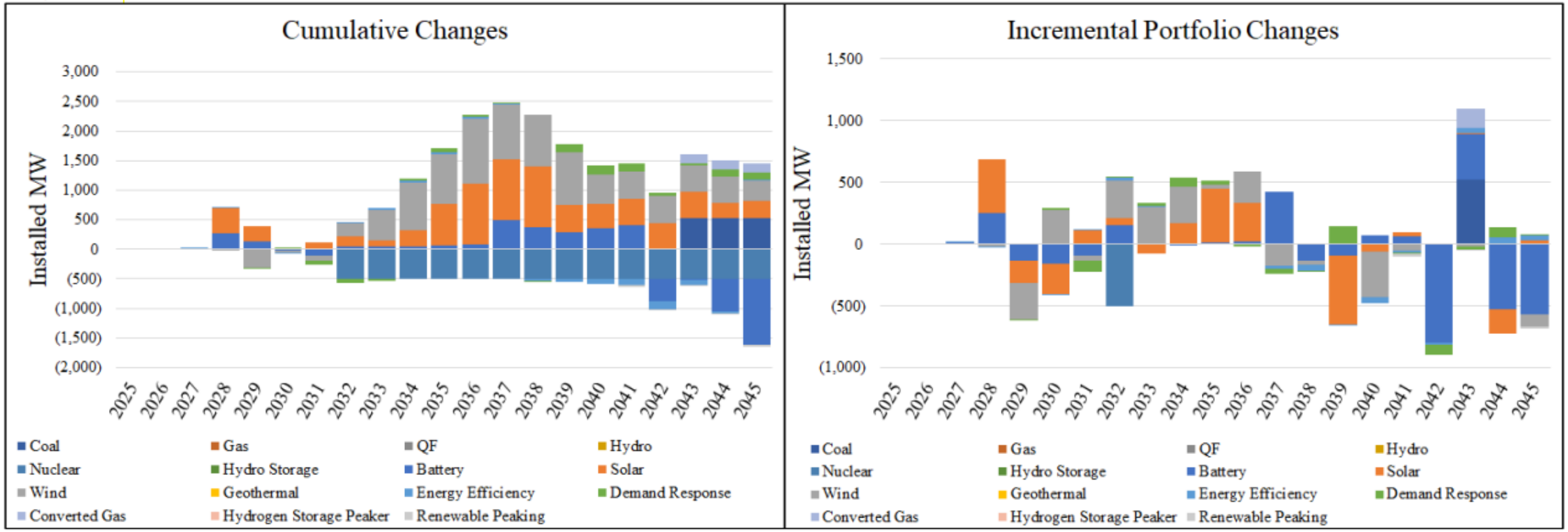
- PacifiCorp is currently negotiating an off-take agreement with TerraPower:
  - From Chapter 7: *The Company is implementing an innovative commercial energy acquisition structure that allows Natrium benefits to flow to customers while ensuring those customers are not burdened with first-of-a-kind technology cost and risk.*
- The structure of this deal is inconsistent with consideration as a deferrable resource.
  - Natrium modeling is not based on supply-side resource cost and performance estimates.
  - PacifiCorp will not be reliant upon Natrium for capacity/reliability.
  - Unlike proxy resources in the preferred portfolio, the online date is chosen by TerraPower (resource cannot be avoided or deferred to a later date).
  - Arrangements are still expected to be completed by end of 2025.

After inputs to the Utah 2025 IRP were locked down, the expected commercial operation date for Natrium was moved back to the end of 2031 (modeled as Jan. 1, 2032).

- Variant analysis evaluating portfolio selections in the absence of Natrium were discussed in Chapters 9 and 10 of the 2025 IRP.
- From Figure 9.19, without Natrium, moderate amounts of additional renewable resources are added, primarily in 2032 and beyond.

(Q6) Natrium Resource

Figure 9.19 - Increase/(Decrease) in Proxy Resources with No Nuclear



While wind and solar costs are forecasted to decline in the 2025 IRP, bringing resources online earlier can spread out PTCs – once PTCs expire resources can be curtailed at zero cost. Replacing Natrium with wind and solar thus results in some earlier additions.

Natrium produces more energy per megawatt, relative to wind or solar, and at more valuable times.

(Q7) Capital Structure Assumptions

	2025 IRP/Utah 2025 IRP		24-035-04 Order	
	Debt	Equity	Debt	Equity
Percentage	55.80	44.20	55.57	44.43
Cost of Debt / Return on Equity	5.09	9.60	5.21	9.375
Overall Rate of Return	7.08		7.06	

Capital structure inputs used in the 2025 IRP/ Utah 2025 IRP are similar to those set by the Utah Public Service Commission in Docket No. 24-035-04.

- The assumed capital structure is embedded in the levelized annual build cost modeled in PLEXOS and used to calculate the avoided cost of displaced proxy resources.
- Higher cost of capital would increase avoided costs slightly – most of the avoided cost comes from the build cost, rather than the carrying cost.
- In an IRP/RFP context, the after-tax weighted average cost of capital is used as the discount rate. A higher discount rate reduces the value of benefits that occur further into the future, relative to benefits in the near term.

PacifiCorp has not determined what capital structure to use in pending Request For Proposal (RFP) dockets.

- Capital structure is more important when utility-owned resources are being compared against power purchase contracts – pending RFPs in Oregon do not allow for benchmark or build-own-transfer-agreements that would result in utility-owned resources.

Thank you!

PACIFICORP®

POWERING YOUR GREATNESS